Q. Please state your name, business address and position with PacifiCorp (the Company).

A. My name is Stan K. Watters. My business address is 825 NE Multnomah, Portland, Oregon, 97232. My present position is Vice President of Wholesale Energy Services.

**Qualifications**

Q. Please describe your education and business experience.

A. I joined the Company in 1982 and I have held various positions in engineering, finance, and wholesale prior to my current position. In my position as Vice President of Wholesale Energy Services, I am responsible for the Company's wholesale sales and trading functions including the economic dispatch of PacifiCorp's system resources. I graduated from Oregon State University in 1981 with a Bachelor of Science in Civil Engineering.

**Purpose of Testimony**

Q. What is the purpose of your testimony?

A. My testimony addresses the Company's overall power supply strategy during the deferral period, focusing in particular on the cause of the significantly higher net power costs incurred above the level included in rates and the actions that the Company took to keep net power costs as low as possible.

**The Company's 2000-2001 Power Supply Strategy**

Q. Would you describe the Company's overall approach in securing the necessary power supply to serve its retail customers?

A. Yes. During the 2000-2001 period, the Company generally relied upon the market for balancing the system portfolio and supplying incremental requirements. As part of this strategy, PacifiCorp, similar to any load serving utility, uses a complex process that evaluates its load and resource balances well in advance of the scheduled delivery of energy, so that the Company can meet its objectives of reducing risks associated with market price and supply while serving customers safely and efficiently. This process is continually revisited because load and resource balances can and do change frequently due to a variety of factors. Those factors include higher or lower than expected retail loads, changes in market prices, thermal unit outages, weather and hydro conditions.

Q. Please explain the major causes of the significant increase in net power costs the Company incurred during the deferral period.

A. The significantly higher net power costs experienced by the Company during the deferral period are primarily attributable to the extraordinary increase in wholesale prices beginning in late spring 2000. This situation was exacerbated by other, unrelated circumstances including (1) the impact of the sale of Centralia, (2) the Hunter 1 failure, (3) abnormally poor hydro conditions, and (4) retail load growth. The Company's losses were further compounded by the impact of FERC's unanticipated rule changes adopted June 19, 2001, and the resulting price decreases in market prices after those FERC rule changes. I will discuss each of these circumstances in my testimony.

**Extraordinary Increase in Wholesale Prices**

Q. Please describe the extraordinary and volatile price conditions that existed in the wholesale market during the deferral period.

A. Beginning in late spring 2000, wholesale energy markets changed unexpectedly. Prices and price volatility surged dramatically to unprecedented levels, and the supply became more constrained. For example, the daily on-peak wholesale market price for January 2000 at COB averaged $31.62 per MWh compared to $180.82 per MWh in June 2000, $129.96 per MWh in July 2000 and $213.73 per MWh in August 2000. The significant increase in price volatility was evident in the changes in market spreads between peak and off-peak prices. For example, the COB average market spread between peak and off-peak prices changed from $6.62 per MWh in January 2000 at COB to $117.94 per MWh in August 2000.

Q. Did market price forecasts vary by a large amount from May 2000 through the deferral period?

A. Yes. As shown on Exhibit No. 1, the variation in market prices was at unprecedented levels, and the prices were substantially higher than our historical experience. Using August 2001 as an example, in late May 2000 the forecasted price for this particular month was $80 per MWh, in April 2001 the forecast price increased to $598 per MWh, and then unexpectedly declined dramatically to $67 per MWh in July 2001.

Q. How did market prices compare to the level included in rates for short-term purchases?

A. The average market price of short-term purchased power included in the Company's rates was approximately $21.50 per MWh compared to an average price of approximately $139 per MWh during the deferral period, or approximately 6.5 times the level included in rates. In this environment, the Company's strategy of relying on the market to fill in during the "peaks" of a generally balanced load and resource situation became very costly. The market purchases used to fill in the occasional short-term deficiency in supply were no longer priced at $20-$30 per MWh, but at prices dramatically higher, as I discussed above.

Q. What were the Company's options for meeting load requirements with the near term implications of these unforeseen price levels and volatility?

A. Based upon forward price projections available at the time, it appeared likely that market prices would stay higher than historical averages for the foreseeable future. We had two options for meeting near term resource requirements: the Company could buy forward to cover the bulk of resource requirements or leave most of the balancing to the extremely volatile day-ahead and real-time markets.

Q. How did the Company respond?

A. The Company rejected reliance on the day-ahead and real-time markets to balance its system, and determined that the inclusion of some forward purchases provided a better balance to meeting load requirements. As the Commission is aware, the failed California deregulation attempt featured reliance on these markets. This approach resulted in the bankruptcy of one major utility, a second major utility teetering on the brink of bankruptcy, and the state of California with an additional

$9.0 billion of debt related to energy purchases that it did not expect. The Company did not adopt the California approach, but rather chose to prudently buy resources forward, in support of the load requirements during the deferral period to hedge risk.

Q. When did the Company begin buying energy to meet load requirements for the deferral period?

A. The Company began purchasing energy during June 2000 to meet expected energy requirements during the deferral period. At that time the purchases were predominately for the 2001 summer season because the loss of Hunter 1 and the upcoming poor hydro conditions were not known. Provided, as Exhibit No. 2, is a summary of forward purchases executed for June 2001, July 2001 and August 2001 prior to June 18, 2001.

Q. Does the Company employ a specific process when balancing its system forward?

A. Yes. The Company continually evaluates its position and requirements so that it buys and sells energy in the most advantageous locations to optimize the Company's system and keep costs as low as possible given the various constraints present in the Company's system and the market at that time. Sales and purchases are entered on a gradual basis because large transactions can have the unintended effect of driving prices either significantly higher or lower. In addition, a gradual process utilizes the concept of price averaging, which is beneficial.

Q. Did the Company undertake additional activities to handle the high price volatility and reduce its exposure to the wholesale market?

A. Yes. The Company undertook a series of non-traditional transactions to deal with the unexpected risks the Company was experiencing under the unprecedented conditions occurring in the wholesale energy market. In addition to buying energy forward, the Company entered the following transactions to reduce reliance on the wholesale market.

- **Purchase of Incremental Generation** – the purchase of generation output via bilateral contracts from entities owning generation that was previously off-line.
- **Purchase of Displaced Generation** – the purchase of generation output from entities that either had invoked, or intended to invoke, their option to displace operating generation and take retail service at tariff prices.
- **Purchase of Operating Reserves** – the purchase of load reduction options that qualify as a supplemental reserve pursuant to North American Reliability Council criteria, thus, freeing up additional PacifiCorp generation to serve load.
- **10/10 and 20/20 Challenge Programs** – the implementation of two customer buyback programs under which residential customers that reduced their load 10 percent or 20 percent from 2000 summer peak levels were rewarded with a 10 percent or 20 percent price reduction on their remaining energy consumption.

- **Advertising** - the implementation of advertising programs in conjunction with the 20/20 and 10/10 programs to make customers aware of the high cost of resources and to encourage voluntary conservation.
- **Gadsby Peakers** – the lease of 100 MW of gas peakers at the Company's Gadsby Power Plant from May 15, 2001 through November 15, 2001. The additional generation provided intermediate peaking capacity and reduced the Company's exposure to the forecast high market prices during super peak hours.
- **Demand Exchange Program** – the implementation of a daily demand exchange program whereby qualified retail customers are able to bid in verifiable load reductions.
- **Continued Conservation** – the continuation and expansion of existing conservation programs, such as the Compact Fluorescent Light Program whereby customers are given compact fluorescent lights and educated as to their use.
- **Load Reduction** - securing bilateral agreements with retail customers to curtail load for various time periods.
- **Incremental Transmission** - the acquisition of incremental transmission rights to improve the Company's ability to delivery power to our customers.

Q. Did the Company's customers benefit from these transactions?

A. Yes. Customers benefited from the fact that these programs helped insure supply to meet load requirements. In addition, some customers benefited monetarily from customer buy-back programs where the savings were shared with customers. For example, customers that had generation were paid the cost of generation plus an amount of the difference between the day-ahead power market and the cost of generation. The cost of generation was based on the heat rate of their unit(s) multiplied by an appropriate gas index used to reflect their fuel cost plus variable O & M on their generation. The Company then shared the difference between this cost of generation and the index price of electricity at an appropriate delivery point into the Company's system. This structure insured that the customer recovered their cost of generation and received a profit on the difference between the day-ahead power market index and the generation cost. All of PacifiCorp's customers received a benefit of power purchases at prices below the day-ahead power market prices.

Q. Was the Company also facing a supply risk during the deferral period?

A. Yes. As shown on Exhibit No. 3, there were a significant number of power emergencies declared in California. During 2000 and through the first few months of 2001 parts of California experienced rolling blackouts, which affected hundreds of thousands of customers. Further, there were forecasts that the 2001 summer season would be even worse and that the problem could spread to other parts of the WSCC.

Q. What did the Company do to reduce the risk that supplies would be inadequate?

A. The Company's strategy of buying forward and the other innovative transactions the Company entered ensured that customers had adequate power supplies. As a result, our customers had none of the supply interruption problems encountered by the California utilities.

**Impact of Other Factors**

Q. Apart from these conditions in the wholesale markets, what other factors contributed to the high power costs during the deferral period?

A. As I mentioned above, the extraordinary circumstances in the wholesale market were exacerbated by other, unrelated factors including (1) the impact of the sale of Centralia, (2) the Hunter 1 failure, (3) abnormally poor hydro conditions, and (4) retail load growth.

Q What was the impact of the Centralia sale?

A. The Company sold the Centralia plant to TransAlta prior to the run up in wholesale market prices that began in May 2000. The Centralia transaction was approved by this Commission (in Order No. 28296) as well as the other state commissions that regulate the Company. This sale, net of the associated replacement power contract with TransAlta, eliminated approximately 1.2 million and 1.4 million MWh's from the Company's long-term resource portfolio in 2000 and 2001, respectively.

Q. Did the Company indicate in the Centralia proceeding that it would be relying on market purchases to replace the Centralia output?

A. Yes. As described in Order No. 28296, the Company indicated that without Centralia, it intended to balance its loads and resources with market purchases. (Under the Company's medium market price forecasts, customers were shown to be better off if the plant were sold.) This is the strategy the Company pursued, as a majority of the replacement power was purchased from TransAlta, with the balance of the requirement obtained from the general market. There was a recognition at the time of the Centralia sale that the economic analysis associated with the Centralia transaction was sensitive to small changes in critical assumptions. The Commission recognized as well "the vagaries inherent in long-term forecasting," and agreed with Staff's characterization of the Company's decision to sell "as an exercise of business judgment." (Order No. 28296)

Q. What was the Hunter 1 failure, and how did that affect the level of power cost deferrals?

A. On November 24, 2000, the Company experienced a catastrophic outage at its Hunter 1 unit, a 430-MW baseload generating station. This outage, which lasted through May 8, 2001, contributed approximately another .3 million and 1.1 million MWh's of short-term purchase requirements in 2000 and 2001, respectively.

Q. How did hydro conditions affect the level of power cost deferrals?

A. The 2000-2001 water year, commencing on October 1, 2000, was second worst water year on record. These poor hydro conditions added another .5 million and 2.3 million MWh's of short-term purchase requirements in 2000 and 2001, respectively.

Q. What was the impact of load growth?

A. The Company's retail load growth in 2000 and 2001 added additional short-term purchasing requirements above the level included in rates. The Company's strategy has always been designed to match loads and resources, thereby minimizing the extent of the Company's exposure to purchases from the wholesale market. As a result of load growth, the Company's resources were needed earlier than expected. Of course, without the significant increase in wholesale market prices, the slight mismatch between projected and realized loads and resources would not have been expensive. Combined with the conditions in the wholesale markets, however, the failure to achieve a precise matching of loads and resources -- an impossible feat under the best of circumstances -- had exaggerated consequences.

Q. Given these circumstances, how much has the Company relied on the wholesale market to balance its system load requirements?

A. As Table 1 below shows, the Company generally matched its short-term sales and purchases fairly well prior to 2000. The circumstances described above caused the Company to increase slightly its reliance on short-term purchases in 2000 and 2001. Had these circumstances not occurred, net market purchases would have been 4.1% in 2000 and the Company would have had a net short-term sales surplus during the first 10 months of 2001of approximately 1.1 percent. Even with all of these impacts, net short-term purchase requirements in 2000 and 2001 represented a fairly small amount – about 6.6 percent and 7.1 percent respectively- of the Company's system requirements. This means that the

Company was not being overly aggressive in the wholesale market and exposing customers to unreasonable market price risk.

**Table 1**
**PacifiCorp 1996-2001**
**Net Short-Term Purchases as a Percentage of System Requirements**

| Year | Total System Load (Million MWH) | Net Short Term Purchases (Million MWH) | % of System Requirements |
|---|---|---|---|
| 1996 | 62.9 | 0.9 | 1.4 |
| 1997 | 66.1 | 1.8 | 2.7 |
| 1998 | 68.3 | 2.3 | 3.4 |
| 1999 | 67.5 | 1.7 | 2.5 |
| 2000 | 68.1 | 4.5 | 6.6 |
| 2001[1] | 52.3 | 3.7 | 7.1 |

[1] Through October 2001

**<u>The Impact of FERC's Price Mitigation Measures</u>**

Q. Although you claim that PacifiCorp's customers benefited from purchasing power below the day-ahead power market, wasn't there a risk associated with buying forward?

A. There is always some risk in forward-looking transactions, because variables can and do change, as I explained above. That is why the Company continually evaluates the options for minimizing risk. In this case, the Company decided that the risk of balancing the system forward coupled with the risk of falling prices due to various factors was less than the potentially unlimited risk of balancing the system in the extremely volatile day ahead and real time markets.

Q. Was the Company successful at reducing its exposure to the wholesale market?

A. Yes. Based on the Company's load and resource position and the average cost of that position on March 6, 2001, the Company had a mark-to-market value of approximately $700 million associated with its forward purchases for the ensuing year. In other words, had the Company been able to close all of its forward purchases on that date, at the then current forward price curve prices, net power costs would have been approximately $700 million lower than they would have been had the Company not previously engaged in forward purchases. Therefore, the Company had prudently met its objective of reducing market price risk. (Actually closing the Company's position at that time was not an acceptable alternative, however, as it would have defeated the purpose of the forward purchases: the Company would have been exposed to unlimited risk for the energy still expected to be necessary to meet load requirements.)

Q. Wasn't the risk associated with forward purchases increased by the fact that the Company and numerous other parties had urged FERC to impose wholesale price caps?

A. It is true that various interested parties and individuals including senators, governors, public utilities and municipalities had requested price caps. Given that the Bush Administration and FERC repeatedly stated that price caps would not be implemented, however, the Company had no reason to believe price caps or other measures would be implemented that would effectively lower prices. For these reasons, the Company prudently acquired resources to limit risk. As a matter of fact, the Company's opinion was only reinforced when the FERC implemented "Soft Caps" in January 2001.

Q. Please explain.

A. When the Soft Caps were implemented they tended to do more damage than good. The price caps did not have a firm dollar limit and were limited to the state of California. Power marketers soon realized that power could be acquired in California under the price caps, moved outside the state, mixed with other power and resold back to California at prices well above the price caps. The failure of the soft caps only reinforced the Company's view that "hard" price caps would not be implemented by FERC.

Q. Without these price caps, did the Company expect that wholesale market prices would fall in the near future?

A. No. The Company believed that extremely high wholesale prices would continue until new gas fired resources came on-line to provide adequate supply. With construction lead times in the range of two and three years, depending upon the type of plant built, the Company expected that wholesale prices would not start to decline until at least late spring or summer of 2002.

Q. Did the Company monitor actions at FERC and other agencies to remain informed about potential changes that could affect prices in the wholesale markets?

A. Yes. The Company monitored formal proceeding as well as statements by individual FERC Commissioners in various public forums. The Company's senior management attended a special FERC Western states forum in Boise at which then-FERC Chairman Curt Hebert forcefully reiterated the Commission position against price caps. Company officials met with other key federal energy policy makers throughout the period to gain insight. Based on the information the

Company obtained, we believed there would be no changes forthcoming from the FERC that would materially affect the price of energy in the wholesale market. As a matter of fact, as late as May 26, 2001, Vice President Dick Cheney expressed his strong opposition to any price caps. He stated price caps

> "are a mistake. It's not a solution; it's adding to the problem. There isn't anything that can be done short-term to produce more kilowatts this summer."

With statements like these, the Company had no expectations that measures would be implemented that would lower prices.

Q. How did circumstances change when FERC implemented its price mitigation measures?

A. FERC unexpectedly implemented a new price cap Order effective June 19, 2001. The FERC Order not only placed a cap on market prices, but also fundamentally changed the market place with two other rules that were contained in the Order. First, FERC required generators in California to exclude emission costs from their incremental generation costs. This lowered the fundamental dispatch curve in the WSCC by the level of these emission costs, which at times were approximately $130 per MWh. Second, FERC required each generator in California to offer their power into the market unless their units were legitimately down for maintenance. Generators could no longer withhold generation from the market in order to keep prices high. These two unexpected changes significantly lowered the price of power in the WSCC.

Q. Did the Company anticipate the FERC Order?

A. No. As I explained earlier, there was no reason to expect the implementation of measures that would materially lower prices. And the market did not anticipate the change in market fundamentals. Prior to the FERC rule changes and the fundamental changes in the market, the Company continued to believe that FERC would not implement changes that would significantly alter the market price of energy. Accordingly, the 2001 summer was expected to be robust from an energy use perspective. As shown on Exhibit No. 1, at the end of May 2001 the market forecast August 2001 prices to be $391 per MWh.

Q. Please explain the causes of the significant increase in net power costs during the period following the FERC Order.

A. The primary cause was the sudden and unforeseen drop in wholesale market prices which was precipitated by lower than expected retail loads, lower gas prices and the unexpected rule changes adopted in concert with the FERC Order that was implemented on June 19, 2001. Unfortunately, the Company had hedged against potential market price risk at prices much higher than the historical norm, but less than the then current forward price curve, to cover the usually high resource requirements of the summer peak period, plus the impact of the second worst water year on record. To make matters worse, loads were less than expected because of a cooler summer, customer conservation and a slowing economy. Market prices were driven still lower in part because of lower than expected gas prices. As a result, the once extremely valuable long shoulder period position, which had previously been created through the Company's forward purchases, was now a liability, because the average price of the long shoulder period position was now substantially above then existing wholesale market prices.

Q. What do you mean by "shoulder position"?

A. Sometimes we enter into near-term contracts knowing that some of the power that will be delivered under them is surplus to our needs. There are "standard" products in the market, for example a "Heavy Load Hour" product that provides a "6 x 16" block of deliveries (16 hours per day for six days). To the extent we do not purchase "standard" forward products, we are forced to rely more on hourly purchases at unpredictable prices. Therefore we may purchase a "Heavy Load Hour" product as the most economical and lowest-risk means of meeting our "super-peak" needs during eight hours each day of an upcoming six-day period, with the expectation that we will sell surplus energy in hourly markets for the eight "shoulder" hours of each of those days. At other times, we enter into term contracts and expected load does not materialize, requiring us to sell surplus energy into near-term markets.

Q. Why didn't the Company close some of its surplus shoulder positions prior to the FERC rule changes?

A. There are two primary reasons. First, as I previously mentioned, the Company had no reason to believe FERC would implement effective measures that would materially lower the market price of energy. Second, the Company could not have closed any of the long shoulder period positions before market prices dropped without increasing market price and supply risk during the extremely volatile super-peak period, because the forward market only trades standard products such as 6x16, 5x16 and 7x24 products. Trading standard products to reduce the long shoulder position would have resulted in the Company being further short during the super-peak period and therefore exposed to more risk.

Q. Did other parties buy forward at prices that are now significantly above market?

A. Yes. The State of California for one, through the California Department of Water Resources, bought a significant amount of energy many years into the future at prices that are now quite a bit above market. In addition, several other utilities have requests before various commissions seeking recovery of significantly higher net power costs. The Company's request is thus not an isolated request that should be viewed with skepticism; rather, it is a somewhat common, yet unfortunate, problem that faces many utilities in the WSCC.

Q. Why is it appropriate for the Company to recover the costs of these forward purchases under such circumstances?

A. Utilities were generally encouraged during the period prior to the June 19 FERC Order to engage in such forward purchases to reduce reliance on spot or short-term markets and instead increase reliance on term products. Having engaged in these actions, the Company should have an opportunity to recover the costs we incurred. The Washington Utilities and Transportation Commission ("WUTC"), for its part, has commented to FERC that it would be unfair to penalize utilities, such as PacifiCorp, that prudently purchased in the forward market prior to the FERC Order. In comments filed with FERC on August 17, 2001, the WUTC stated:

> It is fundamentally unfair to preclude load-serving entities from the *opportunity* to recover in wholesale markets the cost of term products they purchased pursuant to load-service obligations incurred in those markets prior to the Commission's action to implement price mitigation. Load-serving utilities are fundamentally different from marketers because they do not have the choice to enter the market—they must obtain the power to serve their statutory obligations. Between December 15, [2000] and June 19, 2001, the Commission admonished purchasers in the wholesale power market to reduce reliance on spot or short-term markets and increase reliance on term products. To ignore now the consequences of costs incurred by utilities that followed that advice would be to punish those that heeded the Commission's directives and, perversely, would benefit those that did not.

(WUTC Comments, p. 12) For the same reasons, we believe we should be provided an opportunity to recover the costs of these forward purchases.

**Conclusion**

Q. Please summarize why the Company's deferred power costs should be recovered in rates.

A. The Company reasonably responded to the extraordinary and volatile conditions in the wholesale electricity markets in the western United States since May 2000 by engaging in forward purchases to minimize availability and price risks to customers. As described in my testimony above, the level of deferral in this proceeding arises from a number of factors beyond the Company's control, including the impact of extraordinary and unprecedented high prices and volatility in the wholesale markets, the Hunter 1 outage, the second worst water year on record and the consequences of actions outside the Company's control – such as the FERC Order and rule changes – on the Company's forward power purchases. Moreover, it would be punitive and unfair to penalize the Company for events beyond the Company's control – primarily FERC's June 19, 2001 Order imposing price caps and new rules – when the strategy followed by the Company to balance its system was prudent based on then-existing circumstances and expected future conditions at the time. Had these unusual and unexpected events not occurred, net power costs would have been substantially lower than the level incurred.

Q. Does this conclude your direct testimony?

A. Yes.